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Evaluation of Hydrocarbon Source Rock Potential of Eocene-Oligocene Akata Formation, Onshore Niger Delta Basin, Nigeria

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Abstract

The pro-delta muds of the Akata Formation, intra-Agbada source units, and Late Cretaceous Shales have all been independently argued by several authors as potential hydrocarbon sources for the known accumulations in the onshore Niger Delta Basin. The geochemical characteristics of the Akata Formation of the Niger Delta Basin are rarely discussed in published reports. Hence, the current study used Total Organic Carbon (TOC)/Rock-Eval Pyrolysis data to evaluate the organic richness, organic matter provenance, petroleum generation potential, and thermal maturation of twenty-four (24) ditch-cuttings of the Akata Formation recovered from an exploratory well. The results of this study revealed that the shale samples of the Akata Formation have TOC contents of greater than 1.0 wt.% and could be regarded as a good source rock. The source rock properties of the Akata Formation show a poor petroleum generation potential, with the predominance of type IV kerogen. The values of maturity parameters (T_{max} and Production Index) suggest that the shale samples have no potential to generate hydrocarbons. The results show little likelihood of generating hydrocarbons in commercial quantities from Akata Shale.

Keywords: *Eocene-Oligocene Akata Formation; Niger Delta Basin; Source rock potential; Hydrocarbon generation; Type IV kerogen.*

1. INTRODUCTION

The Niger Delta Basin is the twelfth largest oil province containing roughly 2.3% of the known reserves of gas and oil in the world (Esegbue *et al*., 2020). However, there are arguments regarding the rock in the Niger Delta Basin that has the potential to generate a significant amount of hydrocarbons and charge the

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reservoirs (Haack *et al*., 2020). Most known accumulations that occur in shallow water and onshore areas of the basin are thought to have originated partly from the pro-delta muds of the Eocene-Oligocene Akata Formation (Short and Stauble, 1967; Mattick, 1982; Morgan, 2003). However, The Akata Shales are thought to have the lowest volumetric capacity to generate oil for a world-class prolific basin (Tuttle *et al*., 1999).

Lambert-Aikhionbare and Ibe (1984) argued that there would have been minimal fluid release from the Akata Formation because the migration efficiency from the overpressured Formation would have been less than 12%. Doust and Omatsola (1990) proposed that although there may be many source rocks in the Akata and Agbada Formations, the Agbada Formation contains the bulk. Stacher (1995) suggested that the marine shales of the Akata Formation are the only source of rock that is volumetrically significant, and whose burial depth is consistent with the depth of the oil window. Oluwajana *et al*. (2017) and Oluwajana (2018; 2019) generated thermal maturity models for different depobelts in the Niger Delta Basin and found that shales in the Agbada Formation are thermally immature to mature and can generate hydrocarbons, although not in commercial quantity.

Published reports that address the geochemical characteristics of the Akata Formation and their implications for hydrocarbon generation potential are rare. Hence, the present study aimed to evaluate the hydrocarbon generation potential and thermal maturation of shales of the Akata Formation on the eastern flank of the Niger Delta using TOC/Rock-Eval Pyrolysis data (Figure 1). The study utilized available information on the exploration well 'Akata-1'.

1.1 Geologic Settings

Late Jurassic rifting along the West African margin persisted into the Middle Cretaceous (Esegbue *et al*., 2020). As the African and South American plates separated as a result of rifting, the Niger Delta Basin was formed (Whiteman, 1982). The development of the Niger Delta took place in separate mini-basins with tectonic configurations ranging from extensional to translational and compressional toe-thrust zones (Figure 1; Adegoke *et al*., 2017).

A significant marine transgression ended the building of Cretaceous pro-deltas in the lower Benue trough, marking the beginning of the Paleogene-Neogene Niger Delta Basin (Mattick, 1982). Owing to the underlying lithosphere's slow thermal cooling, as the continental margin subsided, massive volumes of deltaic sediments prograded across it and were deposited directly on the oceanic crust at their seaward extent (Mattick, 1982; Reijers, 2011). Middle-Late Eocene sediments build up over the edge of the African continent, southern Anambra Basin, and west of the folded Abakaliki High (Cretaceous) (Reijers, 2011; Assez, 1989).

Oligocene and younger sediments gradually thicken in the direction of the continental shelf (Assez, 1989). The Cross River Delta lobes and Niger-Benue merged, as the delta proceeded along a single broad front during the Miocene due to the uplift of the Cameroon Mountains in eastern Nigeria and neighbouring Cameroon and continuous delta progradation (Whiteman, 1982). During the Pleistocene lowering of the sea levels, the River Niger cuts valleys through its delta, and as the sea level steadily increases, the troughs are being filled till today (Assez, 1989). Originating in the late Pleistocene, the present-day delta documents significant regressive-transgressive patterns associated with eustatic sea-level variations during the last glacial period (Bustin, 1988).

Short and Stauble (1967) identified and detailed the Paleogene-Neogene stratigraphy of the Niger Delta, identifying three Formations namely Akata, Agbada, and Benin (Figure 2). Eocene to Recent Akata Formation comprises thick marine shale with some deep-water turbidites (Doust and Omatsola, 1990). Thin sandstone lenses occur near the top of the Akata Formation, particularly near contact with the overlying Agbada Formation (Assez, 1989). Based on restricted energy circumstances and a low oxygen supply, the formation is thought to have formed during a lowstand (Avbovbo, 1978; Esegbue *et al*., 2020). Owing to the diachronous nature of the deposition in the basin, the Eocene witnessed the deposition of the paralic Agbada Formation yet persisted until recently (Short and Stauble, 1967). Agbada Formation is a sequence of sandstones and shale that take place throughout the delta's subsurface (Assez, 1989). Typically, the Agbada Formation exhibits a fluvial-deltaic depositional characteristic (Tuttle *et al*., 1999).

The youngest formation in the delta, the Benin Formation, was deposited between the Oligocene and Recent (Esegbue *et al*., 2020; Assez, 1989; Avbovbo, 1978). The Benin Formation is mostly made up of medium- to coarse-grained sandstones that were deposited in braided streams on beaches, intertidal flats, fluvial channels, tidal channels, and sandy alluvial plains (Avbovbo, 1978; Amajor, 1991).

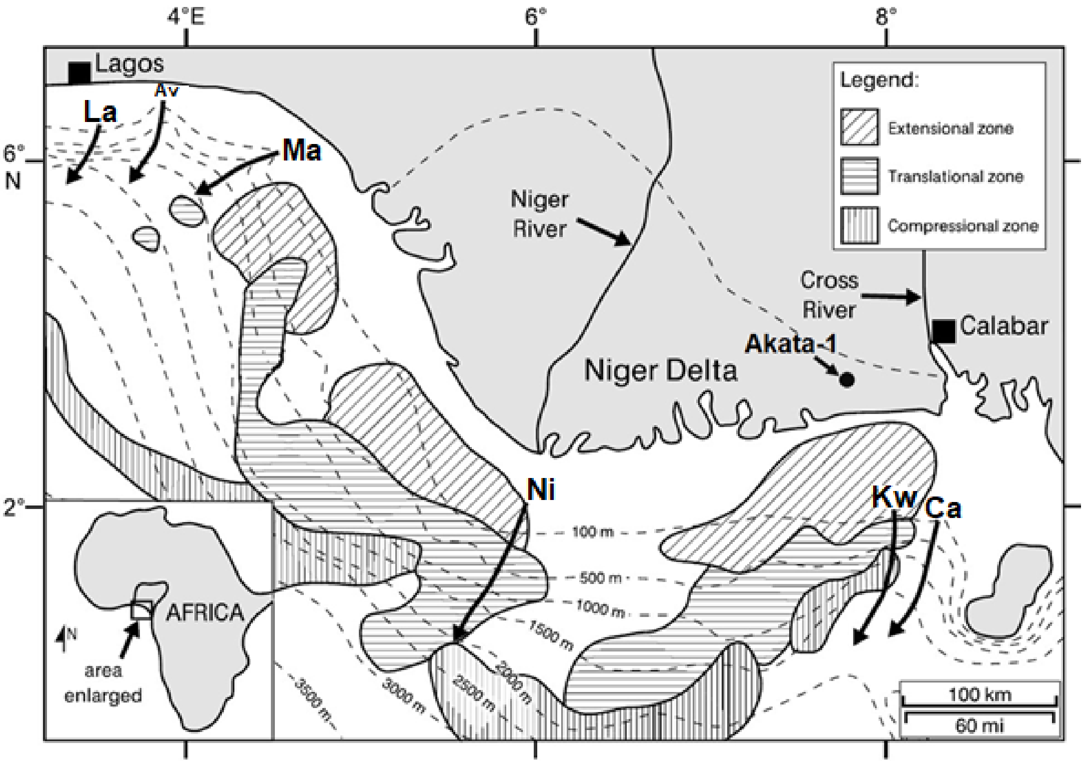

Figure 1: *Map showing the Niger Delta's continental borders displaying bathymetry, tectonic structural type, zones of gravity, and recent canyons below the sea:* ***Abbreviation:*** *La = Lagos; Av = Avon; Ma = Mahin; Ni = Niger; Kw = Kwa-Ibo; and Ca = Calabar (modified after Adeogba et al., 2005). The black circle represents the location of the studied exploration well.*

2. MATERIALS AND METHOD

The studied exploration well, Akata-1, penetrated the Paleogene sequence of the Agbada and Akata Formations (Figure 3). The top of the Akata Formation is 7,180 feet (2,189 meters). At a total drilling depth of 11,121 feet (3,390 meters), the base of the Akata Formation was not reached. Conventional well-log data of the exploration well include spontaneous potential and resistivity logs (Figure 3). Stratigraphically, the Akata Formation lies at the base of the Agbada Formation. The shale of the Eocene-Oligocene Akata Formation is typically dark grey, occasionally sandy or silty, and contains some mica and plant remnants, particularly in the upper section of the Formation. The high and fairly constant spontaneous potential (SP) readings of the Akata Formation make it easy to identify as shale on well logs (Figure 3).

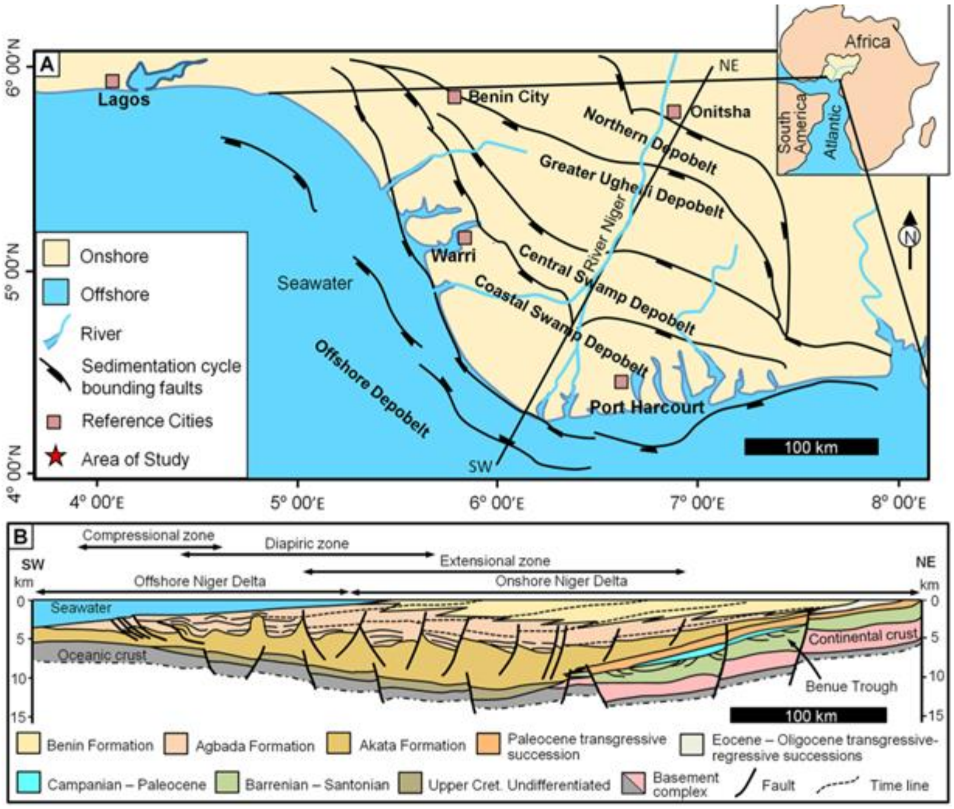

Figure 2: *Regional geological setting of the Niger Delta Basin. (A) Schematic location map of the Niger Delta showing the five depobelts (Ogbe et al., 2021). (B) Schematic stratigraphic cross-section of the Niger Delta Basin showing the various structural zones and the lithostratigraphic formations (Ogbe et al., 2021).*

To measure the free hydrocarbon (S_1), pyrolysable hydrocarbons (S_2), CO_2 released during pyrolysis (S_3), and standard temperature maximum (T_{max}), a Rock-Eval II device was utilized. The readings of the geochemical parameters were recorded from 40-50 mg of dried powdered shale samples. The laboratory analysis used a typical Rock-Eval II/TOC pyrolysis procedure, which included placing the ground-up samples in a crucible and heating them to 300°C for three minutes. After that, the samples were subjected to a monitored pyrolysis program that increased the temperature by 25°C each minute until it reached an ideal temperature of 600°C in a helium environment.

The hydrogen index represents the quantity of pyrolyzed organic molecules or hydrocarbon (S_2) to total organic carbon (TOC) (Peters, 1986) i.e. the hydrogen index is expressed as (S_2/TOC) *100. The oxygen index (OI) is determined based on the ratio of carbon dioxide from S_3 to TOC (Peters, 1986), and is calculated using (S_3/TOC) *100. The production index (PI) is defined as the ratio $S_1/(S_1+S_2)$ (Peters, 1986). The Rock-Eval II pyrolysis results were obtained from the Exploration Department of the Shell Petroleum Development Company, Port Harcourt, Nigeria.

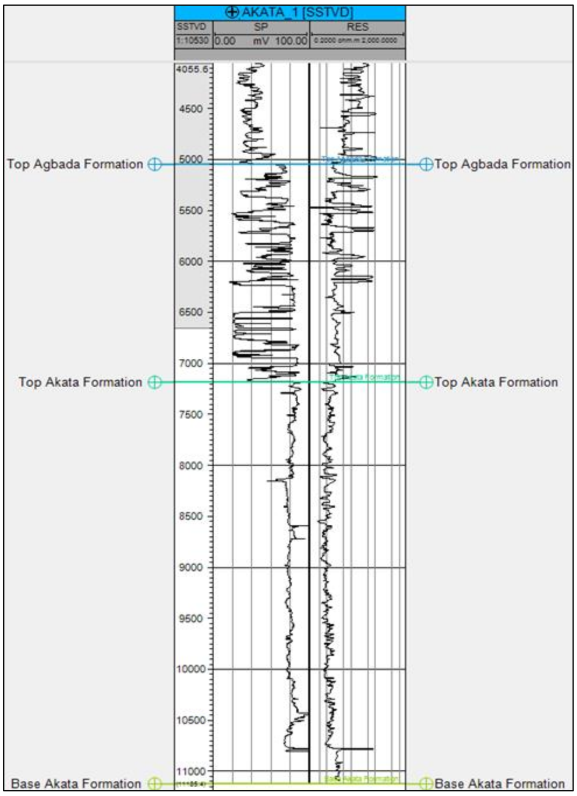

Figure 3: *The type section of Agbada and Akata Formations in a representative well-log data of Akata-1 well, as provided for the study*

3. RESULT AND DISCUSSION

The recovered shale samples of the Akata Formation have TOC values that range from 1.06 to 1.88 wt. % (av. 1.28 wt.%; Table 1). All of the shale samples have TOC levels that are higher than the minimal requirements (≥ 0.5 wt%) needed for a potential source rock (Tissot and Welte, 1984; Wolela, 2010; Figure 4). The TOC values do not significantly decrease with depth (Table 1), this may be an indication of the prevalent homogeneous distribution and deposition of detrital organic matter (Bustin, 1988). The Akata Shale exhibits a range of OI and HI values, specifically 43 to 217 mgCO_2/gTOC and 23 to 55 mg HC/gTOC respectively (Table 1). Even though the examined shale samples are good source rocks, their low hydrogen index (HI) values probably reflect both selective winnowing and higher oxidation as a result of increased permeability (Bustin, 1988) or may be due to high organic production, unfavourable preservation circumstances, and absence of marine zooplankton rich in lipids (Ojo *et al*., 2020). Hydrogen depletion is believed to be caused by extensive oxidation and feeding on organic materials under oxic circumstances (Oluwajana *et al*., 2021).

The cross-plots of OI versus HI and HI against T_{max} were used to classify the kerogen type of the Akata Shale (Figures 5A and 5B). Type IV (biodegraded/inert) kerogen is identified in the OI versus HI plot of the Akata Shale. This suggests that the organic macerals have undergone significant oxidation or alteration, making the kerogen nearly inert, and implying that any remaining carbon cannot generate hydrocarbons (Ehinola *et al*., 2005; Sachsenhofer *et al*. 2017; Oluwajana *et al*. 2021; Meilijson *et al*. 2020; Figure 5A). The plot of HI against T_{max} also confirms that the Akata Shale has no potential for hydrocarbons (Figure 5B). It is not impossible to rule out the mineral matrix influence on kerogen as the cause of the observed low quality (Ehinola *et al*., 2005).

The analyzed shales have S_1 yields varying from 0.04 to 0.18 mg HC/g Rock and exhibit varying S_2 yields of 0.38 to 0.72 mg HC/g Rock. The S_2/S_3 ratio is proportional to the amount of hydrogen in a source rock and indicates the potential to generate oil and gas (Meilijson *et al*. 2020). Less than 1 for the values of the S_2/S_3 ratio indicates that the source rock has little to no potential (Çiftçi *et al*. 2010). The total generation potential ($S_1 + S_2$) values of the Akata Shales range from 0.44 to 0.87 mg HC/g rock (Table 1). A plot of TOC against $S_1 + S_2$ values (Figure 5C) also suggests that Akata Shale is a good source rock, but its potential to generate petroleum is low (El Nady *et al*., 2005).

The pyrolysis temperature at maximum yield of hydrocarbons (T_{max}) values range from 421°C to 433°C while the values of the production index (PI) vary from 0.08 to 0.19. Thermally immature rocks are those with T_{max} values below 435°C while T_{max} values greater than 435°C are required for oil generation (Wolela, 2010). The T_{max} values are less than 435°C and suggest that insufficient burial of the shales prevented significant thermal modification and the generation of hydrocarbons (Sachsenhofer *et al*. 2017; Ojo *et al*. 2020; Meilijson *et al*. 2020). The plot of the production index (PI) values against T_{max} suggests that the shale samples were immature and reflect low thermal conversion levels in the basin necessary for the generation and release of hydrocarbons (Çiftçi *et al*. 2010; Figure 6).

Table 1: *TOC and Pyrolysis results of Akata Formation in Akata-1 well*

Sample Number	Depth, ft.	Depth, m	TOC	S_1	S_2	$S_1 + S_2$	S_3	T_{max}	HI	OI	PI
AKAT_1	7,120	2,170	1.88	0.06	0.43	0.49	4.08	421	23	217	0.1
AKAT_2	7,380	2,249	1.35	0.06	0.38	0.44	1.73	426	28	128	0.12
AKAT_3	7,480	2,280	1.32	0.08	0.43	0.51	1.88	421	33	142	0.12
AKAT_4	8,380	2,554	1.16	0.06	0.51	0.57	1.35	424	44	117	0.09
AKAT_5	8,440	2,573	1.33	0.06	0.67	0.73	1.45	428	50	109	0.08
AKAT_6	8,500	2,591	1.28	0.06	0.61	0.67	1.36	425	48	108	0.09
AKAT_7	8,560	2,609	1.21	0.04	0.43	0.47	1.27	426	36	106	0.09
AKAT_8	8,690	2,649	1.06	0.18	0.55	0.73	0.97	425	52	92	0.25
AKAT_9	8,740	2,664	1.12	0.06	0.47	0.53	0.79	425	42	71	0.11
AKAT_10	8,820	2,688	1.26	0.06	0.57	0.63	0.83	426	46	66	0.1
AKAT_11	8,980	2,737	1.41	0.15	0.72	0.87	1.42	422	51	101	0.17
AKAT_12	9,100	2,774	1.43	0.1	0.61	0.71	0.92	426	43	64	0.14
AKAT_13	9,290	2,832	1.26	0.08	0.58	0.66	0.93	427	44	74	0.1
AKAT_14	9,340	2,847	1.28	0.07	0.7	0.77	0.94	427	55	73	0.09
AKAT_15	9,400	2,865	1.13	0.06	0.59	0.65	0.85	427	52	75	0.09
AKAT_16	9,580	2,920	1.29	0.06	0.52	0.58	0.91	428	40	71	0.1
AKAT_17	9,840	2,999	1.39	0.07	0.55	0.62	1.54	426	40	111	0.11
AKAT_18	9,950	3,033	1.12	0.06	0.5	0.56	0.79	428	45	71	0.11
AKAT_19	10,290	3,136	1.43	0.07	0.51	0.58	0.62	431	38	43	0.12
AKAT_20	10,360	3,158	1.2	0.09	0.58	0.67	0.72	430	48	60	0.13
AKAT_21	10,800	3,292	1.16	0.12	0.62	0.74	0.6	431	54	52	0.18
AKAT_22	10,880	3,316	1.22	0.13	0.66	0.79	0.66	430	54	54	0.16
AKAT_23	11,000	3,353	1.2	0.14	0.62	0.76	0.7	432	52	58	0.18
AKAT_24	11,060	3,371	1.22	0.14	0.6	0.74	0.88	433	49	54	0.19

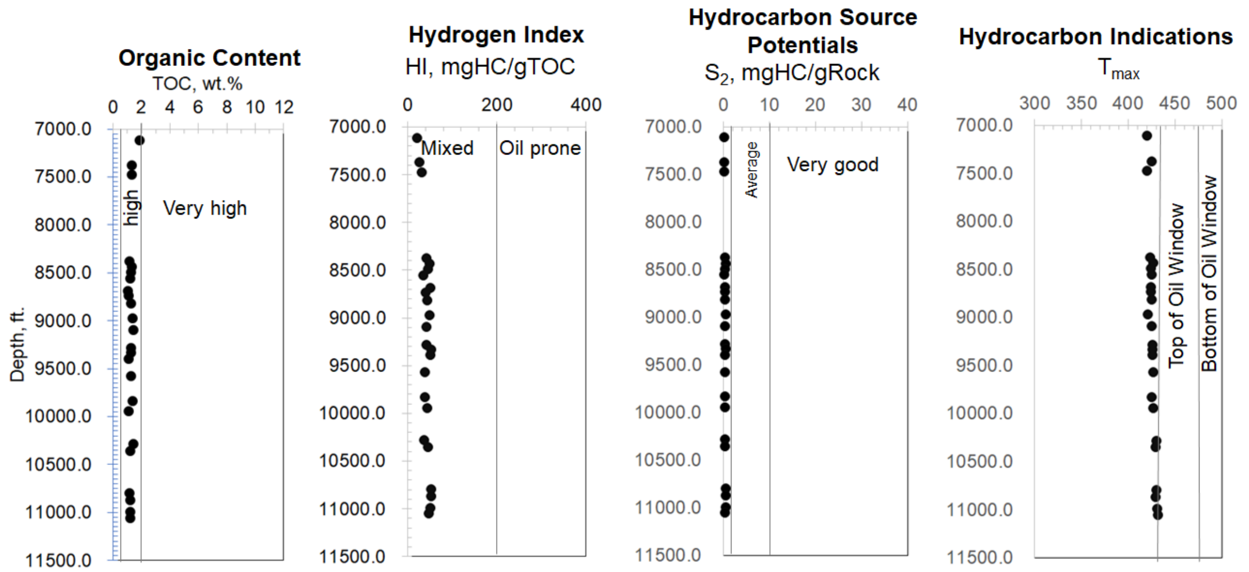

Figure 4: *Correlation of geochemical data for Akata-1 well. The depth of the well is in feet.*

3.1 Source rock consideration

The Akata Formation is the chief hydrocarbon source in the Niger Delta Basin (Ejedawe *et al.*, 1984). The studied shale samples are typical of the shale unit of the Akata Formation and are considered to be a potential source rock for the Niger Delta Basin. The present study has shown that the shale samples of the Akata Formation on the eastern flank of the Niger Delta Basin are presently immature. This is consistent with the work of Bustin (1988), who stated that the shales of Paleogene-Neogene age in the Niger Delta Basin have little to no potential for oil production because the strata lack rich organic source rocks.

Shales of the Agbada Formation are the source of oil in the eastern Niger Delta Basin, while both the Agbada and Akata Formations' shales are the source of oil in the western Niger Delta, according to Ekweozor *et al*. (1979). Ekweozor and Daukoru (1984) argued that the deeply buried Agbada and Akata Formation sections within the main delta axis, in both the east and west areas that are currently exposed to temperatures not less than 70°C (uncorrected, 158 °F), are probable source rocks. The thick Akata Formation, which formed during the quickly prograding sedimentation, had to be the source of the mature charge in the basin. In contrast, According to Esegbue *et al*., 2020, a type II sub-delta source is responsible for a significant portion of the oil in the Niger Delta Basin that has moved into the clastic reservoirs of the Agbada Formation.

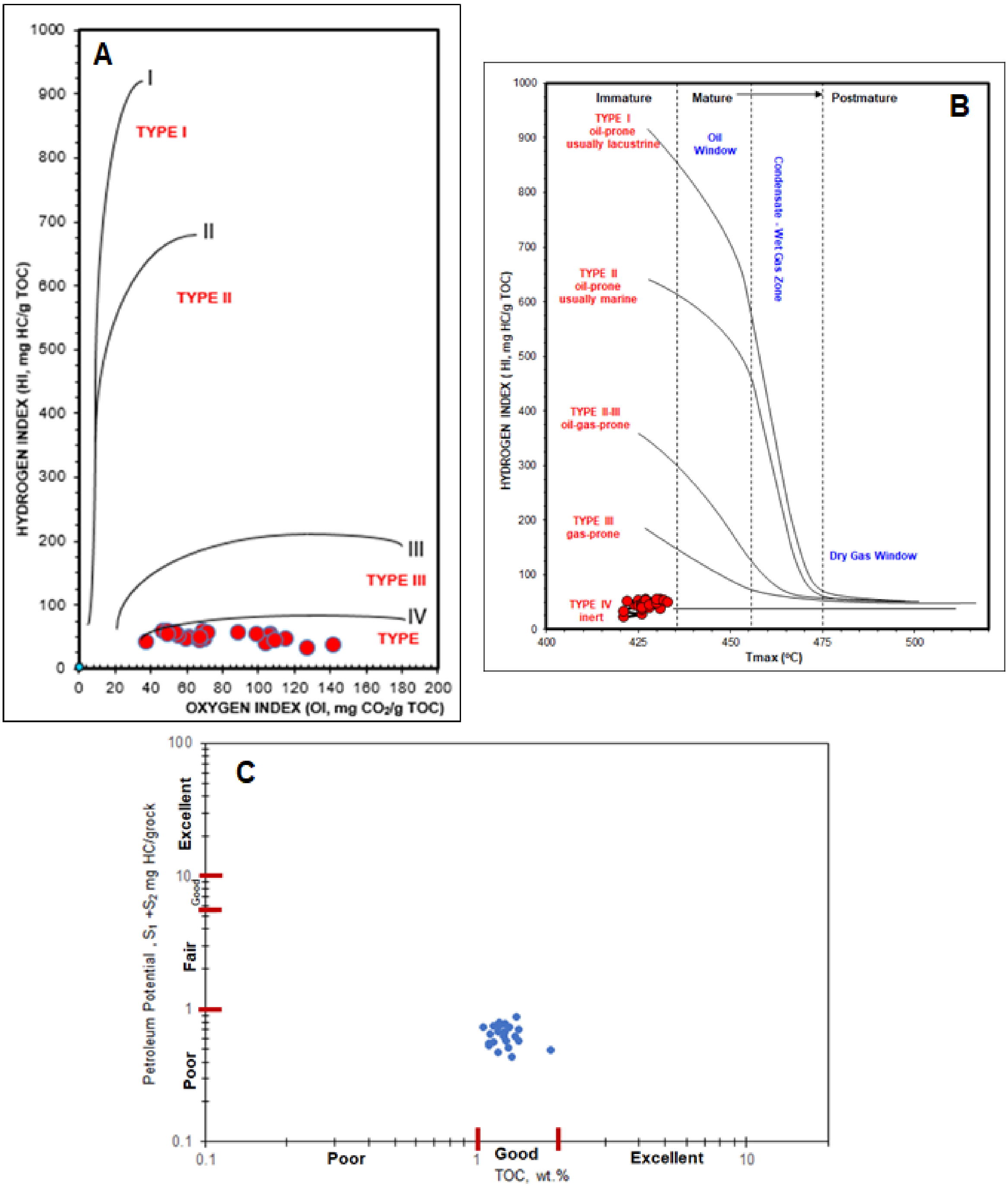

Figure 5: *(A) Kerogen/organic matter type discrimination plots of the Akata-1 well relationships between OI and HI.* ***(B)*** *Cross plot of $S_1 + S_2$ versus TOC.* ***(C)*** *Geochemical correlations between the HI and T_{max}. Type IV kerogens dominated the shale samples analyzed.*

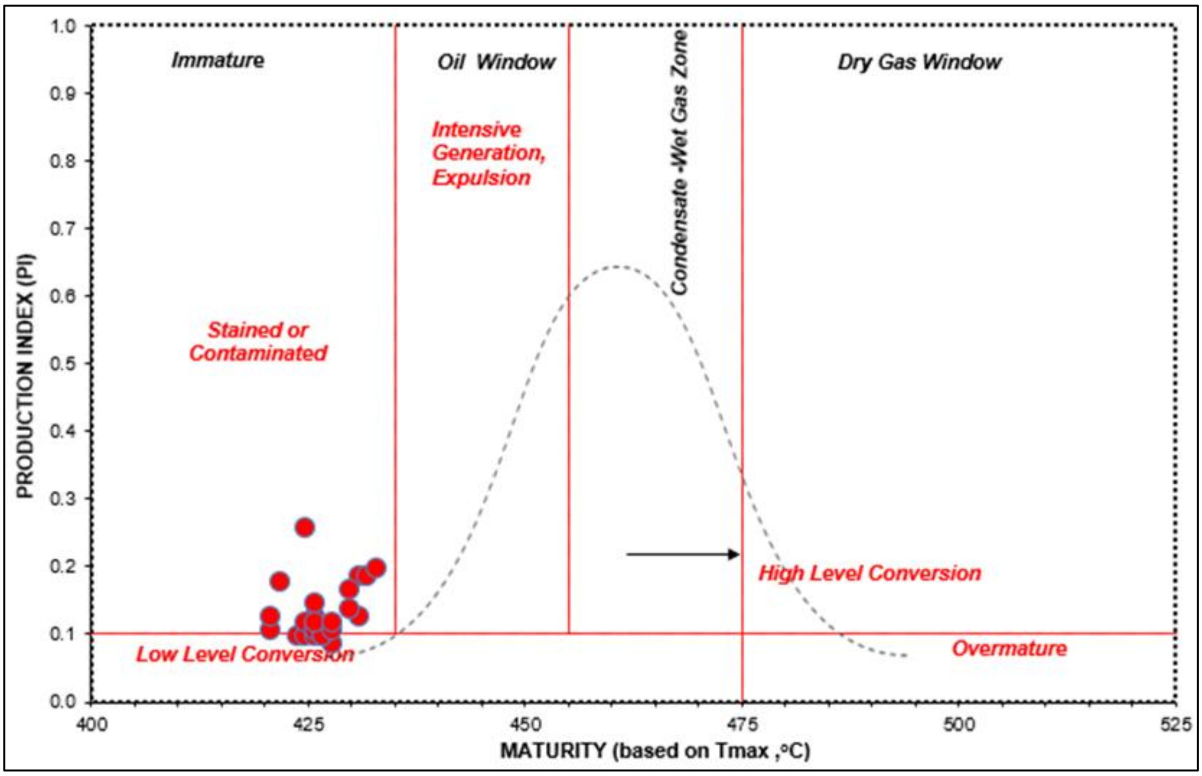

Figure 6: *The maturation level and generative phase of the shale samples are indicated by geochemical cross-plots of the pyrolysis parameter T_{max} vs the PI.*

The Rock-Eval parameters namely pyrolysis temperature at maximum yield of hydrocarbons, and hydrogen and oxygen indices, indicate the immature nature of type IV kerogen, with little or no oil-generating potential. Okosun and Osterloff (2014) reported that the Akata Formation was deposited in shallow water settings at inner neritic to middle neritic paleowater depths based on the ostracod assemblages found in ditch cuttings of the Akata-1 well demonstrated by the dominance of *Loxoconcha* species. With progressively deeper depths, the Akata Shale takes on an abyssal or bathyal nature, perhaps interrupted by a few turbidity-current deposits (Short and Stauble, 1967), where the Akata Shale would be mature and capable of generating hydrocarbons.

4. CONCLUSION

The hydrocarbon generation potential and thermal maturation of the Eocene-Oligocene Akata Formation in the eastern onshore Niger Delta Basin were determined using the results of TOC/Rock-Eval Pyrolysis of twenty-four (24) shale samples recovered from an exploratory well (Akata-1). The following findings might be applied to assess future Niger Delta Basin exploration prospects.

1. The TOC contents of the twenty-four shale samples recovered from the Akata-1 well reflect a good hydrocarbon source rock because it is beyond the threshold limit of 0.5 wt.%.

2. The studied shale samples of the Akata-1 well exhibited a thermal evolution of a Type IV kerogen, HI values between 23 and 55 mg HC/gTOC with a T_{max} range of 421°C to 433°C, hence has no potential to generate hydrocarbon
3. The maturity parameters (i.e., T_{max} and PI) suggest that the Akata Formation is currently at an immature stage of hydrocarbon generation.

The present study has shown that the shale of the Akata Formation in the Akata-1 well is not capable of generating hydrocarbon.

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CONFLICT OF INTEREST

No conflict of interest was declared by the authors.

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